Prepared for the California Public Utilities Commission

Aliso Canyon OII Phase 3 Research, Workstream #2 Approach: Portfolios Framework and Research Methods

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March 30, 2021

Agenda

1 **Workstream #2 overview** — *Matthew DeCourcey, FTI*
- Workstream #1 results
- Analytical tools

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- Request for input

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4 **BREAK**

5 **Gas modeling and gas transmission portfolio** — *Tim Sexton, GSC*
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- Inventory assumption
- Seasonal analysis
- Request for input

6 **Electric transmission portfolio** — *Venki Venkateshwara, FTI*
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- Request for input

Workstream #2 overview

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Analytical overview

Operational Analysis

Simulate the operation of the electric and gas systems on an hourly basis under peak day conditions to determine how reliant they are on Aliso Canyon. Based on those results, specify multiple packages of investments that would allow for the facility to retire without impacting reliability.

Benefits Analysis

Conduct long-run economic analysis to determine which of the investment options is most beneficial and/or least expensive from the ratepayers' perspective.

Production Cost Modeling → **Hydraulic Modeling** → **Identify Investments** → **Economic Modeling** → **Financial Modeling**

WORKSTREAM 1

WORKSTREAM 2

Workstream #1 was completed in early 2021, the Project Team is now finalizing key inputs to be used in Workstream #2 and expects to begin conducting simulations shortly.

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Change in perspective for Workstream #2

Workstream #1

OPERATIONAL ANALYSIS

- Peak day simulation
- Short time-step based on critical hours
- Understanding system changes
- Capacity orientation - focus on MW, MMcf/d

Complete

Workstream #2

COST-BENEFIT ANALYSIS

- Long-term simulation
- Long-term forecasts that include all 8,760 hours/year
- Understanding costs and benefits
- Energy orientation - focus on $/MWh, $/MMBtu

In Process

Key findings from Workstream 1

If Aliso is retired and no other changes are made, a generation shortfall occurs during the highly constrained conditions we modeled. That shortfall defines the "gap" in system capability that must be closed in order to retire Aliso. The gap can be closed with investments that provide enough gas to replace the deliverability required to serve all EG, investments that provide enough non-gas generation to offset EG that otherwise could not be served, or a combination. Note that totals include a slight update vs. values reported in November.

	Peak Hour *(MMcf)*	**Daily** *(MMcf/d)*	**Generation** *(MW)*
2027	32.6	434	4,768
2035	24.2	318	2,866

These totals are subject to change (increase) pending today's discussion based on revisions to modeling inputs.

Investment portfolios

Target

GAS INVESTMENTS

2027: 434 MMcf/d

2035: 318 MMcf/d

ELECTRIC INVESTMENTS

2027: 4,768 MW

2035: 2,866 MW

Design

Gas Transmission	Demand Reduction	IRP Mix	Electric Transmission	TBD
Make investments to restore the SCG Northern Zone plus additional increase to the Southern Zone, if necessary. Review interconnection and upstream capacities. Costs based on utility filings to CPUC and other public datasets.	Expansion of gas-side activities plus new investments assumes significant regulatory support from CPUC, mandates from AB3232, and others. Gas-only, based on analysis of current programs plus public planning studies.	Incremental demand response, storage, and renewables added in the same ratio as shown in the current IRP. New builds are scaled *pro rata* in order to close the MW gap. No new thermal generation is included.	Close the MW gap by adding new electric transmission capability into CA. Scaled up projects that are currently under development. Includes 2035 ISD only since long build times may challenge a 2027 ISD.	A fifth portfolio is to be defined following analysis of the first four infrastructure portfolios based on the results of their analysis. May be a combination of tested portfolios or a new and unrelated investment.

Includes the addition of the electric transmission portfolio, which was added in response to comments received during and after the November Workshop.

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Economic modeling suite

	PLEXOS *(Electric)*	**GPCM** *(Gas)*
Solver	MIP with co-optimization of reserves	RBAC Network Optimizer (custom LP algorithm)
Key topology	Transmission, generation, storage, distribution	Pipelines, supply, demand, storage, LNG
Stochastic	Yes, forced outages	No
Time-step	Hourly	Monthly
Demand	IRP / Phase 2	California Gas Report
Infrastructure inputs	IRP / Phase 2, adjusted for "known and measurables" as described in the November Workshop	Existing pipelines and storage, planned (certificated) projects based on research by FTI and GSC
Forecast period	20-years *(includes extrapolations)*	20-years *(includes extrapolations)*
	https://energyexemplar.com/solutions/plexos/	https://rbac.com/gpcm-natural-gas-market-model-description/

PLEXOS and GPCM are each in widespread use for the simulation of power and gas markets including by utilities, investors, regulators, system operators, and researchers. Models are populated using public and proprietary databases compiled by the Project Team and calibrated to observed markets.

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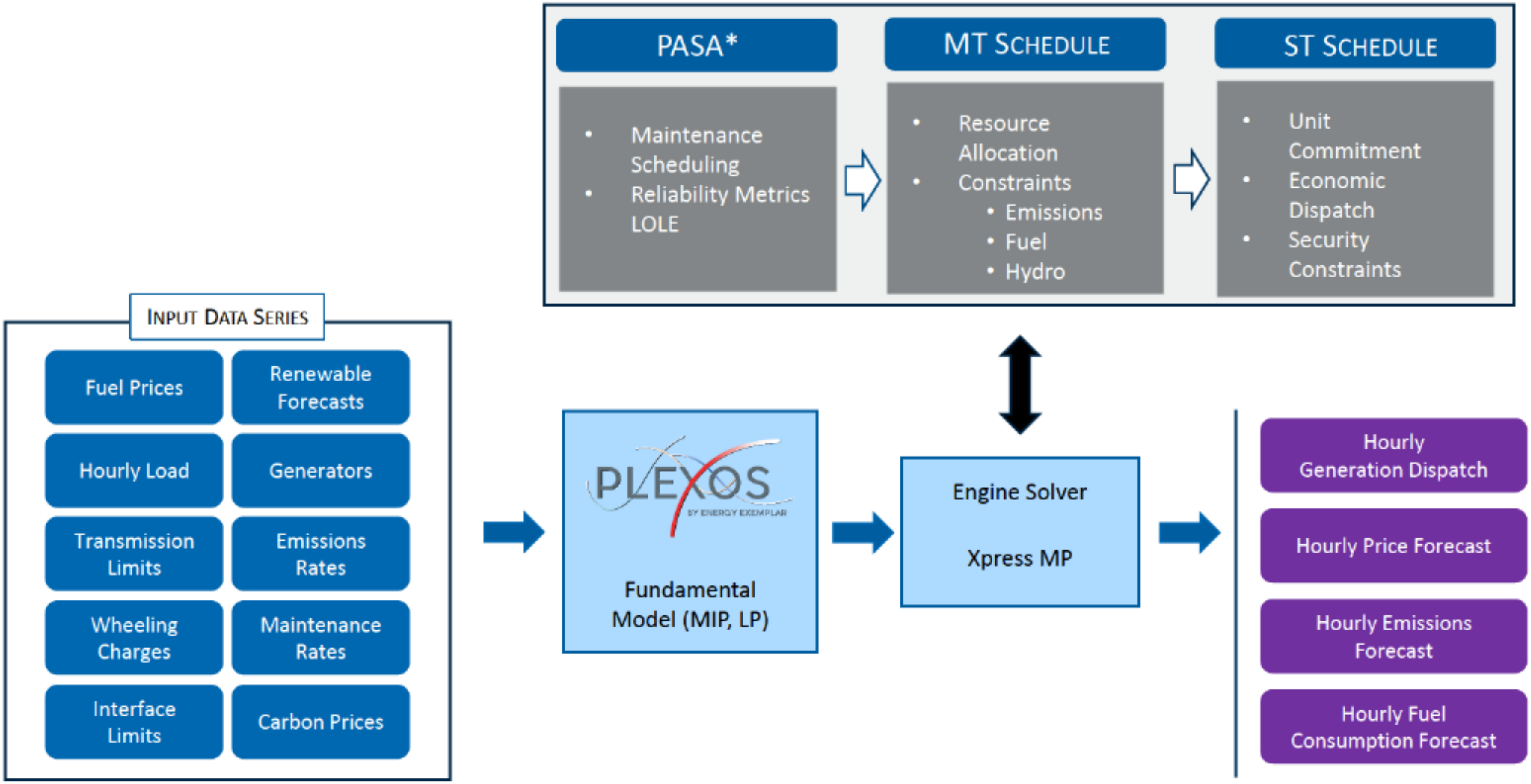
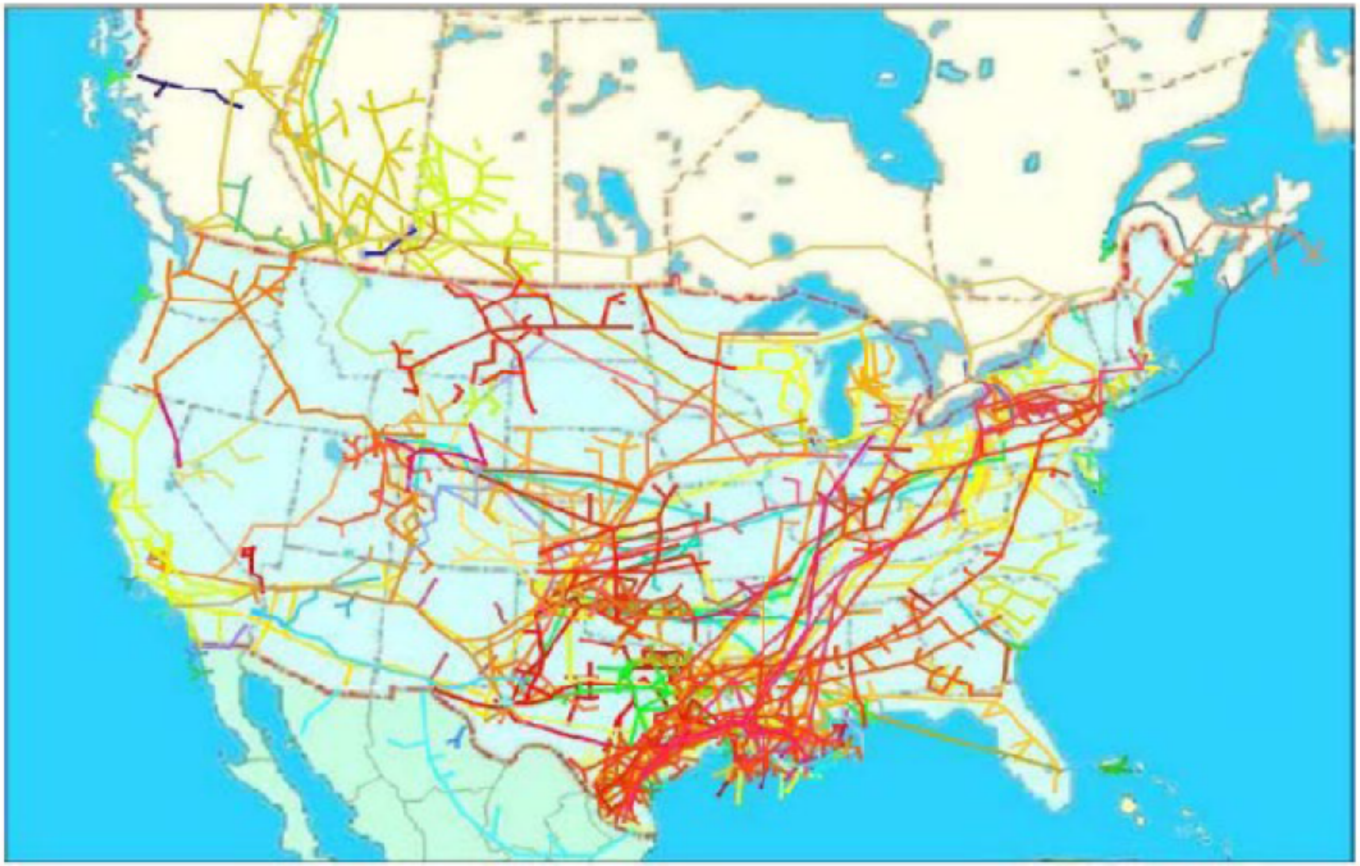
PLEXOS overview



*Projected Assessment of System Adequacy

GPCM

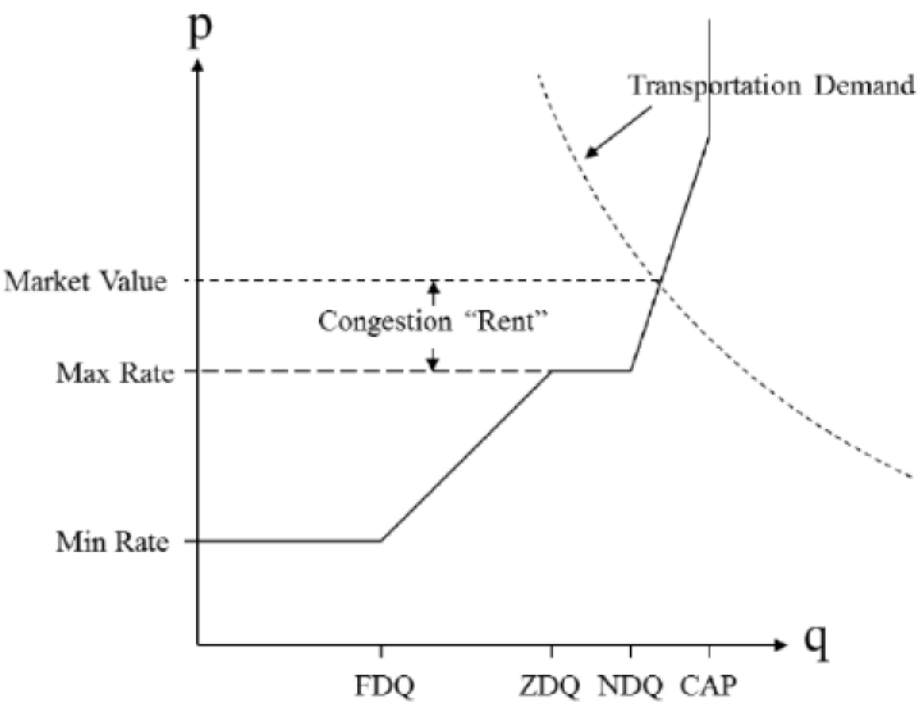


Highly granular, customizable framework that includes:

- 90+ supply areas differentiated by region, play, type etc., with changes in production economics over time
- 200+ pipelines, including interstate and large intrastate systems
- Existing and planned LNG import and export
- Demand differentiated by customer and by type (RES, COM, IND, EG, and vehicles)
- Representation of the major pricing indices – generally aligns with *Gas Daily*

Source: Energy Information Administration

GPCM transportation economics



FDQ = Full Discount Quantity
ZDQ = Zero Discount Quantity
NDQ = Negative Discount Quantity (congestion)

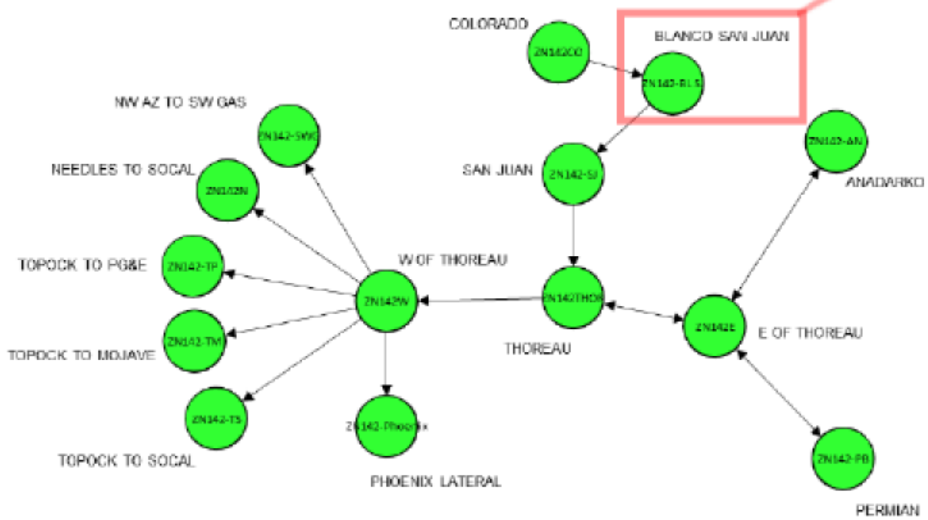
Max Rate = Interruptible Commodity Charge
Min Rate = Firm Commodity Charge
Max Flow = System Capacity of Zone = Deliverability

Prices in supply areas are primarily determined by production economics while prices in downstream markets like California are a function of the commodity cost of gas and the availability of transportation service. In GPCM, transportation costs are priced based on a discounting function. As utilization increases, discounts available to shippers decrease, and vice versa. Under high-demand condition, the economic value of transportation (basis) exceeds the maximum tariff price. Discounting functions are calibrated based on observation of settled market prices.

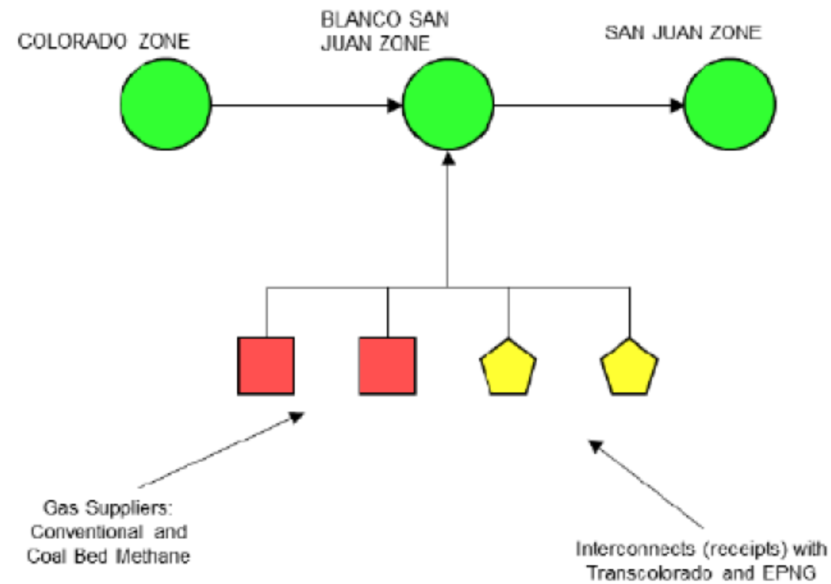
Source: RBAC

GPCM infrastructure representation

Transwestern System*



Blanco San Juan Zone*



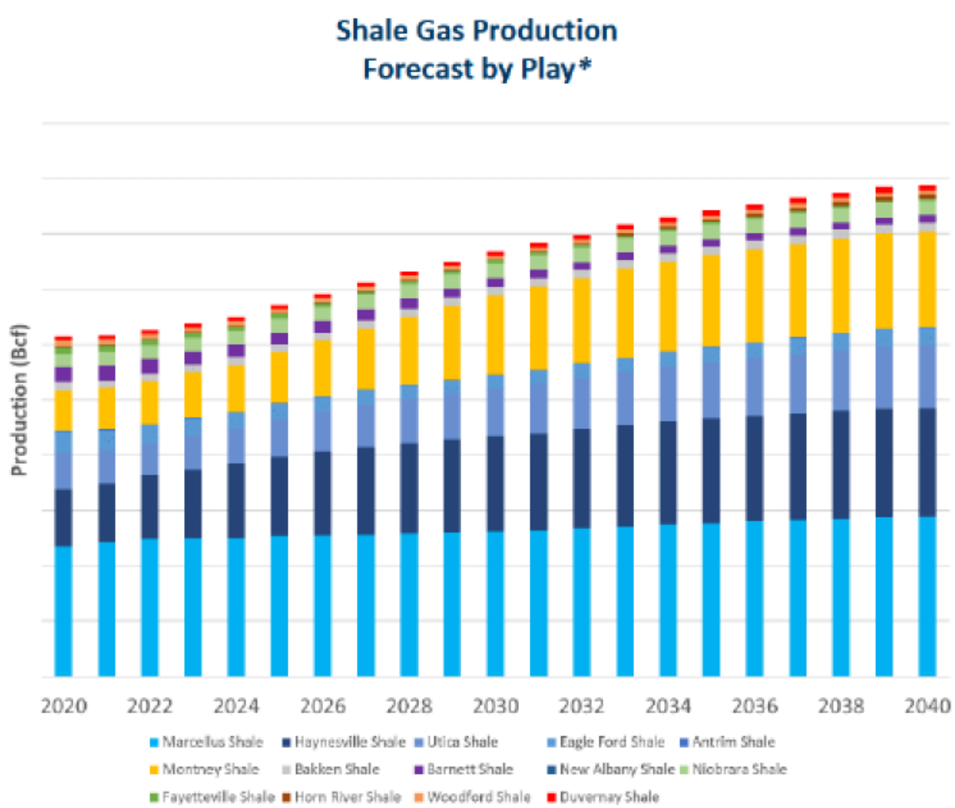
Infrastructure modeled at a high degree of granularity based on real-world configurations and capabilities. GPCM also has the flexibility to change the configuration of the system over time to reflect new builds and other changes.

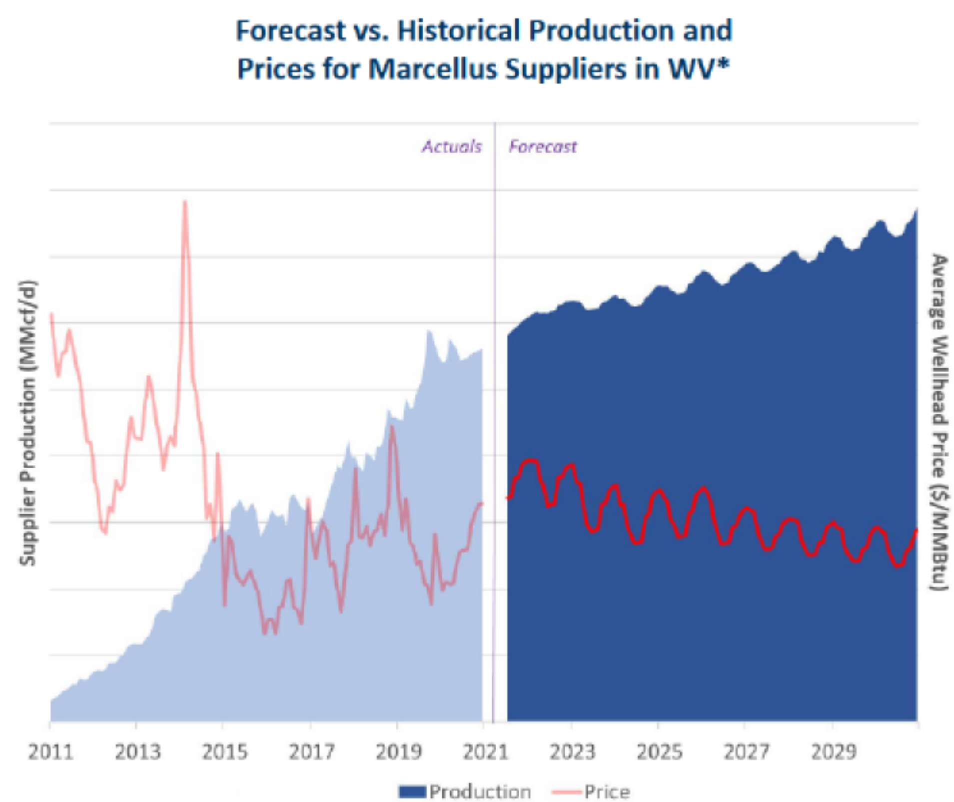
Infrastructure inputs will align with those used during Phase 2 and elsewhere.

** Configurations are indicative only for purposes of demonstration*

GPCM production economics

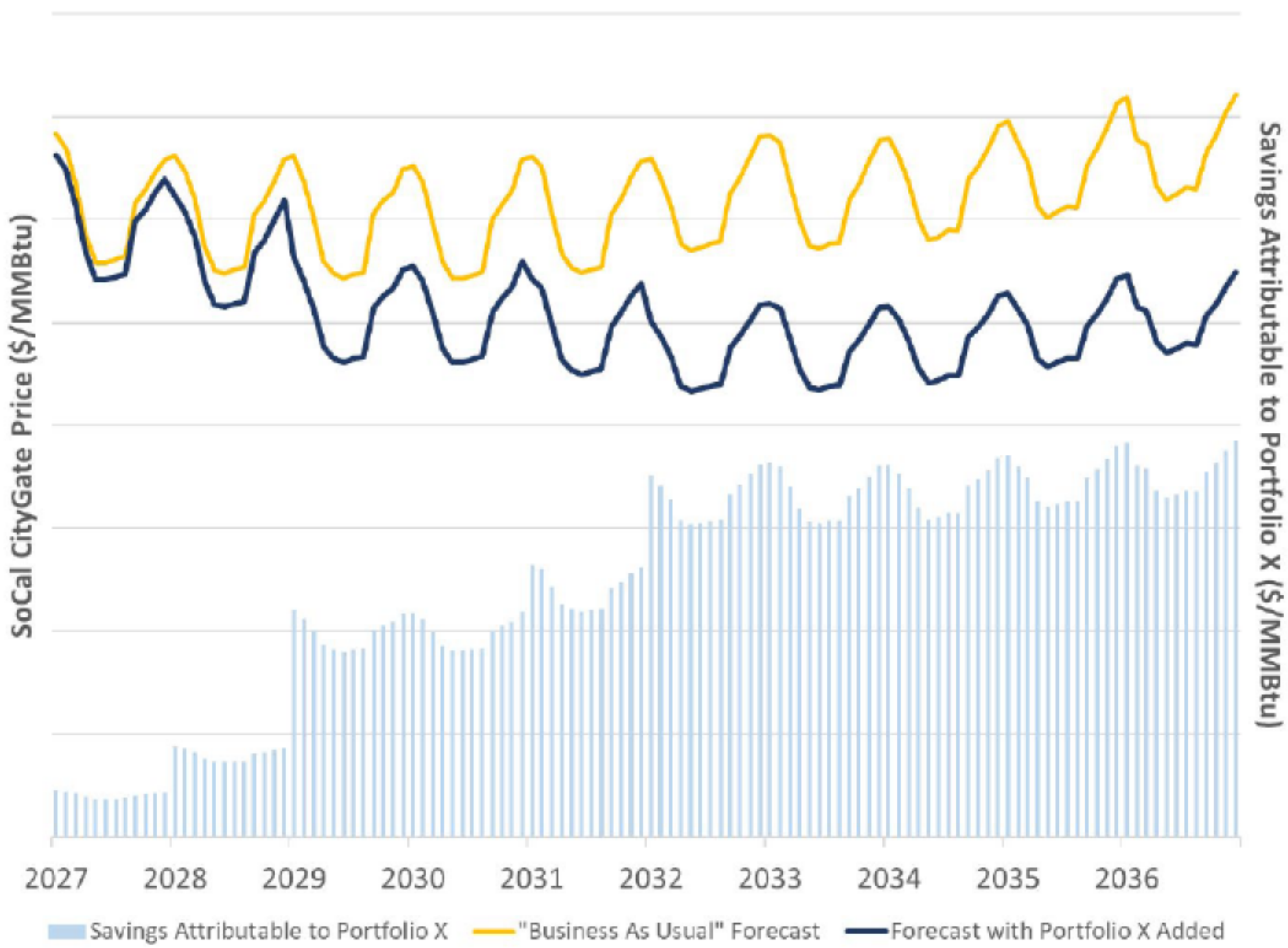
Using historical data from which relationships between production, prices, and other factors are derived, location- and type-specific supply curves are developed, from which production forecasts are derived based on equilibrium supply-demand solutions.





** Results are indicative only for purposes of demonstration*

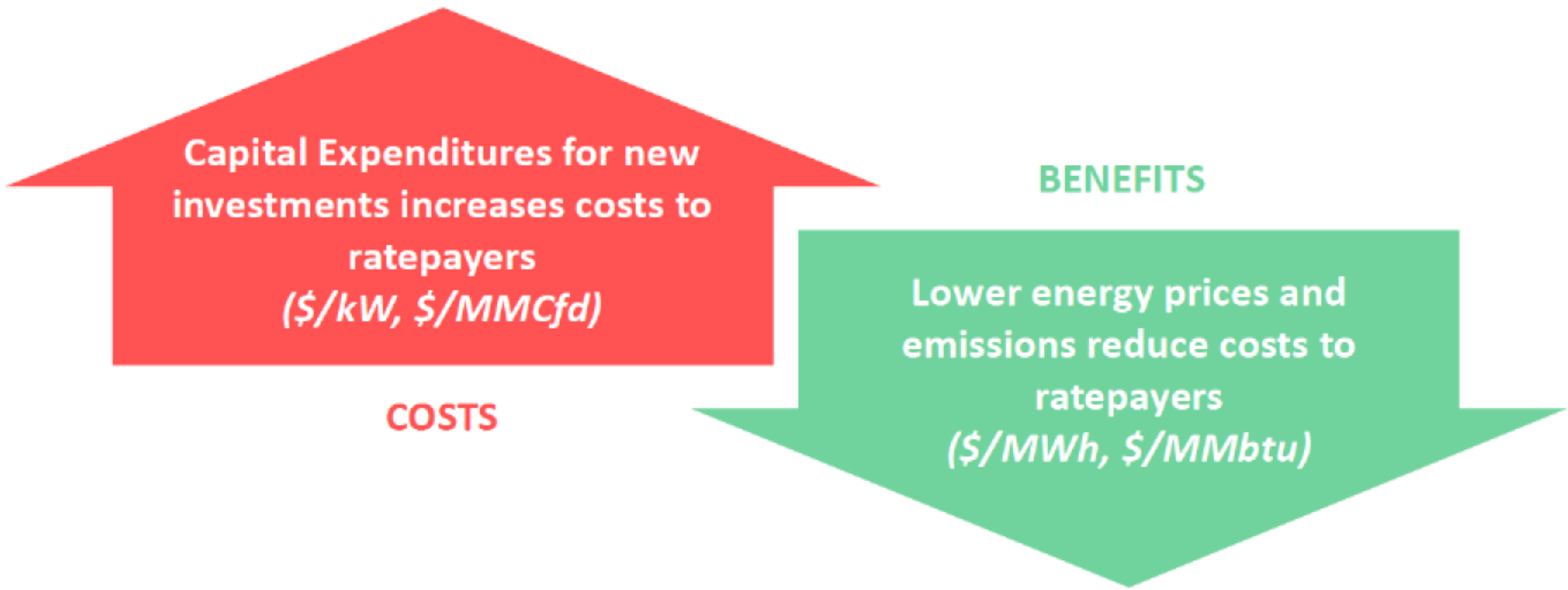
Analyzing gas market impacts from an investment portfolio



Comparing the results of a "Business As Usual" forecast to one that includes one of the investment portfolios, while all other variables are held constant, allows for the estimation of the savings that are attributable to that portfolio.

For each portfolio, this process will be repeated for both the gas (GPCM) and electric (PLEXOS) markets, to capture the total market change attributable to each.

Net benefits



Simulate gas and electric markets using PLEXOS and GPCM to estimate the savings from reduced energy prices and emissions from new infrastructure. Benefits will be compared to capital and operating costs in a financial model, from which Net Present Value ("NPV") of each portfolio will be calculated. The NPV provides the basis for comparison of portfolios.

Workstream 2 overview

Investment portfolios scaled to close the shortfall

1 Long-run simulations of power and gas markets to estimate market impacts

2 Research and analysis of financial costs to build new infrastructure and financial modeling to calculate the NPV of each option

3 Comparison (ranking) of portfolio costs and benefits

Preliminary results expected in Summer 2021

Questions

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Demand reduction portfolio

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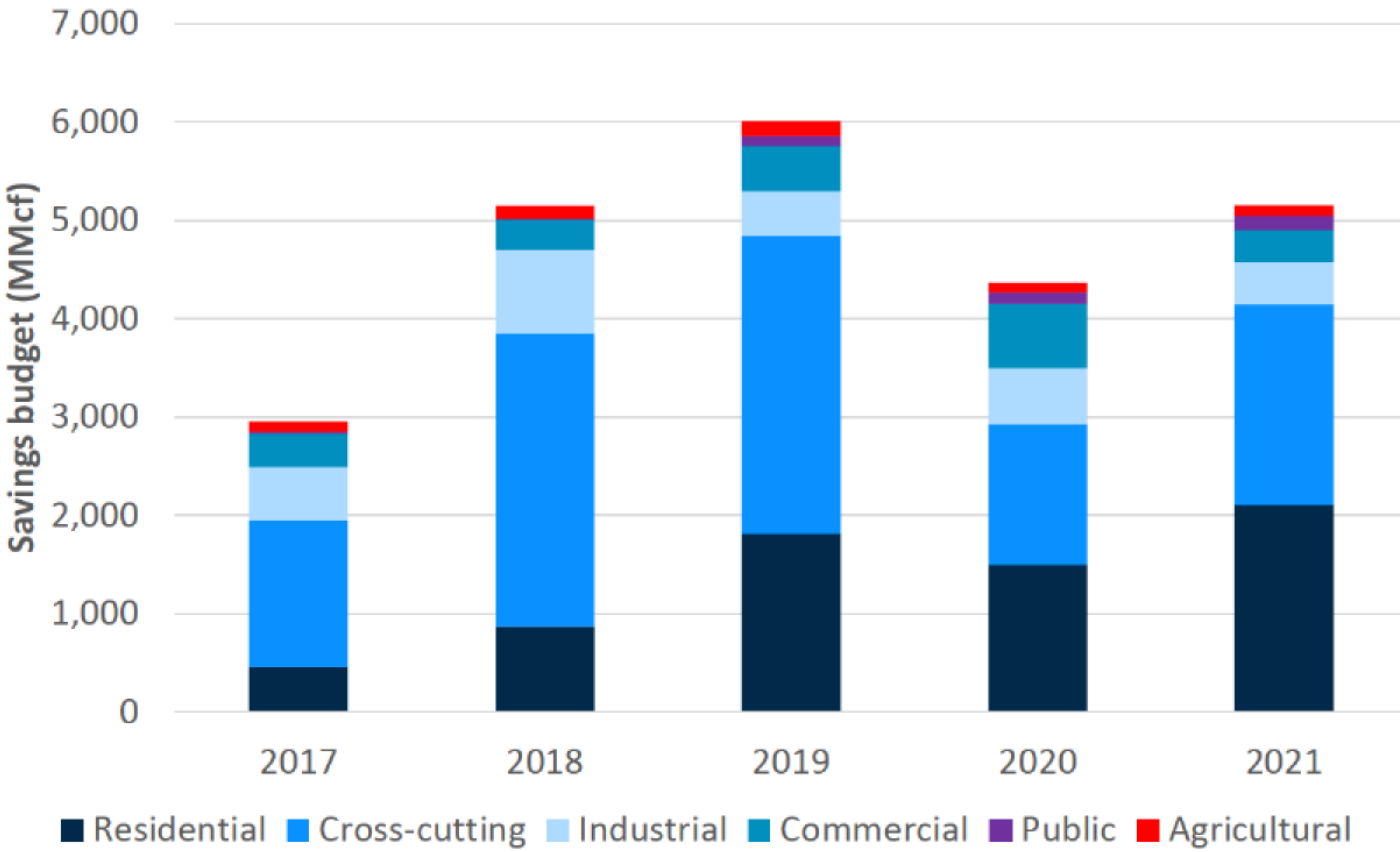
Demand reduction portfolio



Scale existing EE activities to fill the gas gap for each of 2027 and 2035. The Project Team currently intends to scale programs *pro rata* based on the current SoCal Gas program, although other approaches are possible.

Significant increases in program scale assume strong legal and regulatory support.

Source: Analysis by FTI and GSC using data from CEDARS

SCG 2021 EE budget filing

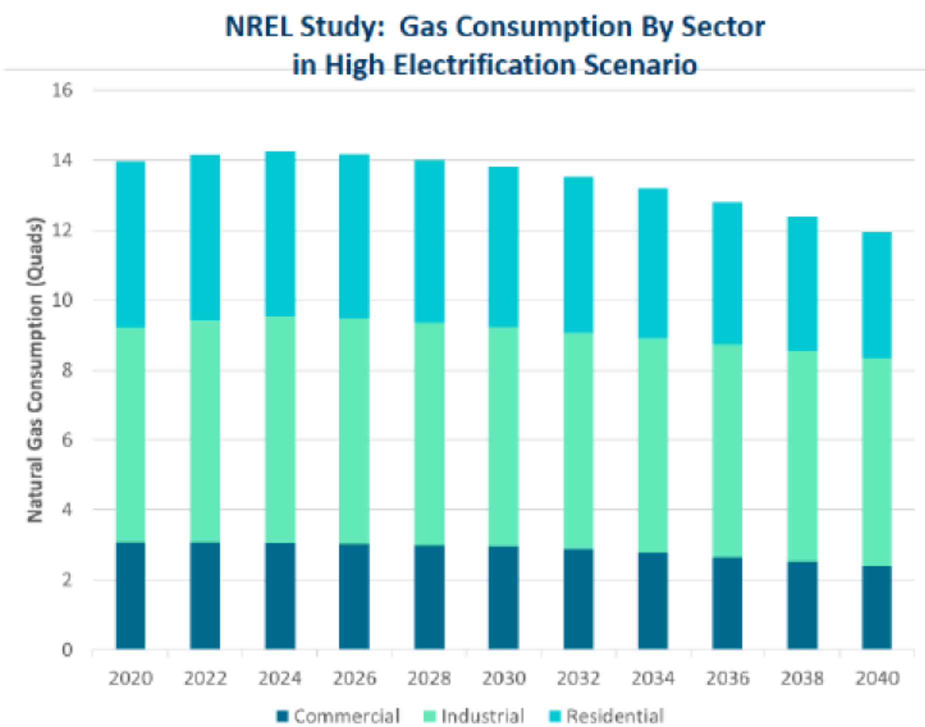
Rank	Program	ID	Savings (MMTherms)	%	Agg. %	Budget ($,000)	Cost ($/therm)
1	Building codes advocacy	*SCG_SW_CSA_Bldg*	10.3	19%	19%	$470	$0.05
2	Residential behavioral	*SCG3824*	10.0	19%	38%	$6,721	$0.67
3	Appliance standards advocacy	*SCG_SW_CSA_Appl*	8.7	16%	54%	$331	$0.04
4	Energy savings assistance	*SCG-ESAP*	6.9	13%	67%	-	-
5	Industrial incentives	*SCG3715*	2.9	5%	73%	$8,045	$2.75
6	LivingWise (Residential)	*SCG3764*	2.1	4%	77%	$2,503	$1.20
7	Federal codes advocacy	*SCG_SW_CSA_Natl*	2.0	4%	80%	$299	$0.15
		Total	**53.5**			**$106,195**	**$1.99**

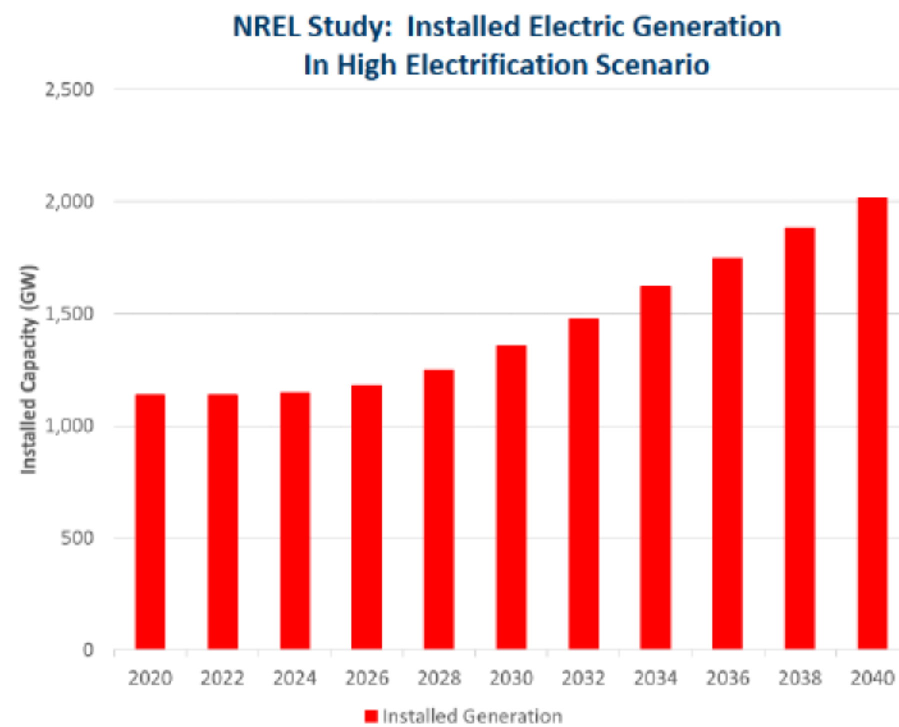
Observations from the SCG 2021 EE budget filing:

- Most savings are concentrated in a small handful of programs
- "Advocacy" programs are the biggest driver of total savings and among the most economically efficient
- Unclear if all programs are equally scalable

Source: Analysis by FTI and GSC using data from CEDARS

Building electrification not expected to be an emphasis





Building electrification, which is supported by AB 3232 and other initiatives, may not help facilitate Aliso Canyon's retirement because reductions in gas demand, which reduce the "gap", are offset by increases in electric demand, which widens it. In January 2021, NREL published its *Electrification Futures Study* which demonstrates the dynamic on a nationwide basis.

The Project Team is not aware of any California-specific data of similar granularity or of any specific reason why the rate at which gas displacement creates the need for new generation should be lower in California than it is elsewhere.

Source: Analysis by FTI and GSC using data from NREL

Requests for input

In addition to other input that participants would like to provide, the Project Team specifically requests comments on the following topics:

1. How can we scale existing EE programs to the required levels to meet the peak-day gap?
   - Is it appropriate to scale programs *pro rata* or should we attempt to differentiate based on cost-effectiveness of specific program elements?
   - Other than the utilities annual filings, what data should be considered?

2. Do you agree with the conclusion that building electrification should not be part of the portfolio?
   - If not, how can electrification help facilitate Aliso's retirement?

3. What influence will AB 3232 have on EE achievement that is not captured in our current approach?

4. What regulatory or legislative support would be required to achieve EE savings sufficient to close the peak-day gap we identified in Workstream 1, for either 2027, 2035, or both?

Questions

???

IRP mix portfolio

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IRP Mix

	2027 Firm *(MW)*	2035 Firm *(MW)*
Wind	583	451
Battery	4,134	2,385
DR	52	30
Total	4,768	2,866

Non-gas additions are in addition to the buildout envisioned in the Reference System Plan, using the same mix of resources. Mechanically, resources added will be scaled up in size in PLEXOS.

Most of the datasets required have already been developed for Workstream 1. We do not currently foresee major issues with this portfolio.

Questions

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Gas transmission portfolio

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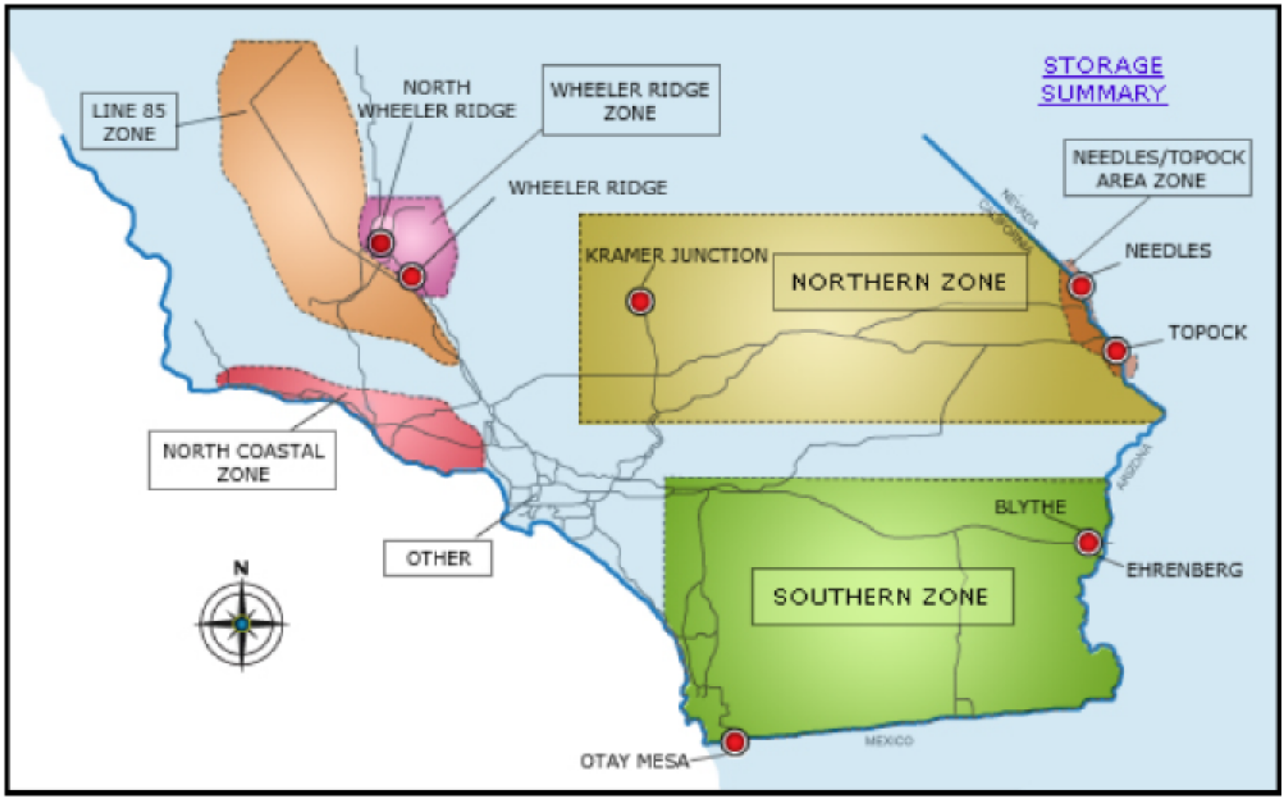
Gas transmission portfolio



Restoration of the Northern Zone to 1,590 MMcf/d replaces Aliso Canyon deliverability with enhanced access to gas delivered from the interstate system. Project specifications and costs to be based on filings made at the Commission, at the FERC, and elsewhere.

Several key issues that could significantly impact our study remain outstanding, including modeling assumptions related to assumed system Receipt Point Utilization ("RPU") and assumed storage inventories as well as the results of a mass balance analysis conducted by the Project Team. We have several specific requests on these topics.

Source: SoCal Gas

RPU background

In Phase 2, an 85% RPU assumption was selected following extensive consultations to capture impacts from exposure to a number of risks:

1. Tolerance for forecasting error
2. Protection against SoCal Gas system pipeline outage
3. Offset potential upstream capacity or supply disruptions

85% RPU selected: CPUC analysis and stakeholder input

Gas transmission inputs independent from those used for other portfolios

Upstream Failures – Phase 3: Gas Transmission Investment Portfolio Analysis

- Lower RPU would result in a perceived need for incremental capacity on the SoCal Gas System
- Incremental SoCal Gas capacity does not offset upstream failures
- RPU should be limited to offset forecasting error and/or outages

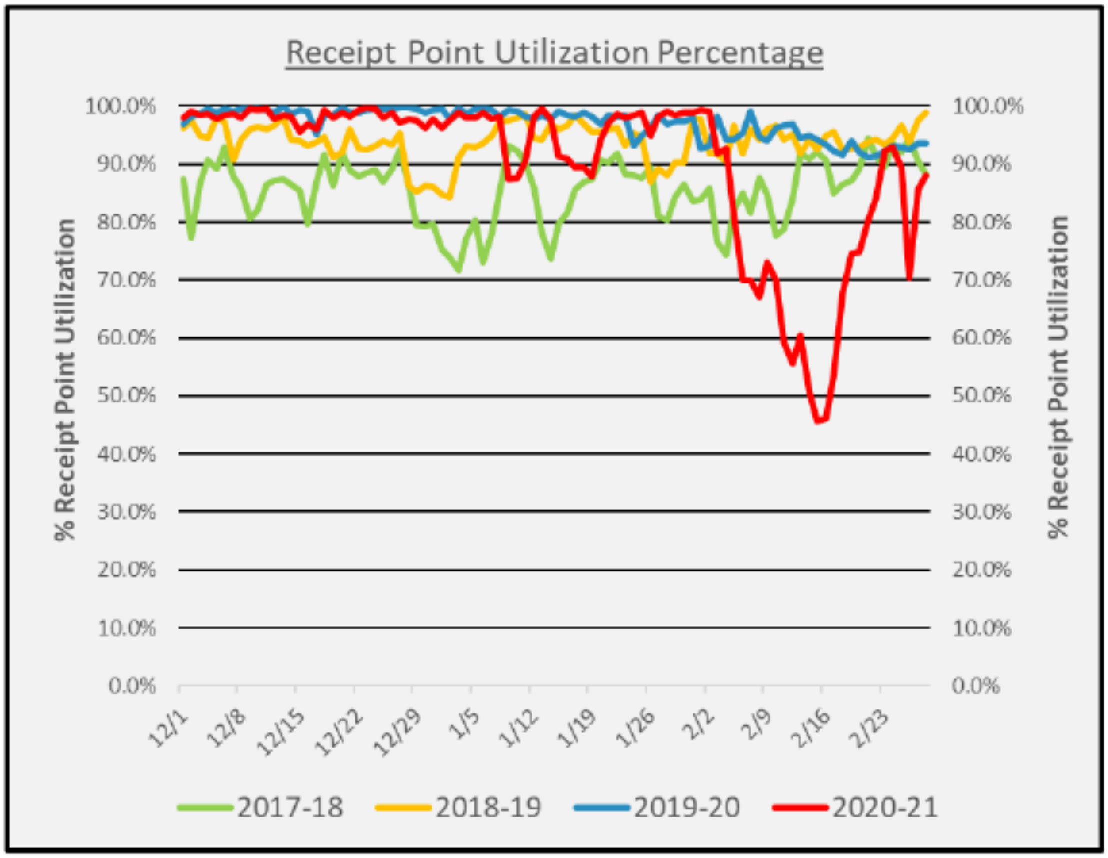
RPU Increase – Phase 3: Gas Transmission Investment Portfolio Analysis

- SoCal Gas customers employed 95%+ RPU over past three winters on high sendout days
- Restoration of SoCalGas system results in more robust system supporting higher RPU

Phase 3: Remaining Investment Portfolios

- No gas system facility changes in remaining investment portfolios
- No compelling reason to change agreed to Phase 2 RPU assumption in remaining portfolios

Recent RPU actuals



1/ *Data sourced from final nomination cycle applicable to each day (Cycle 5 in use since April 2016).*

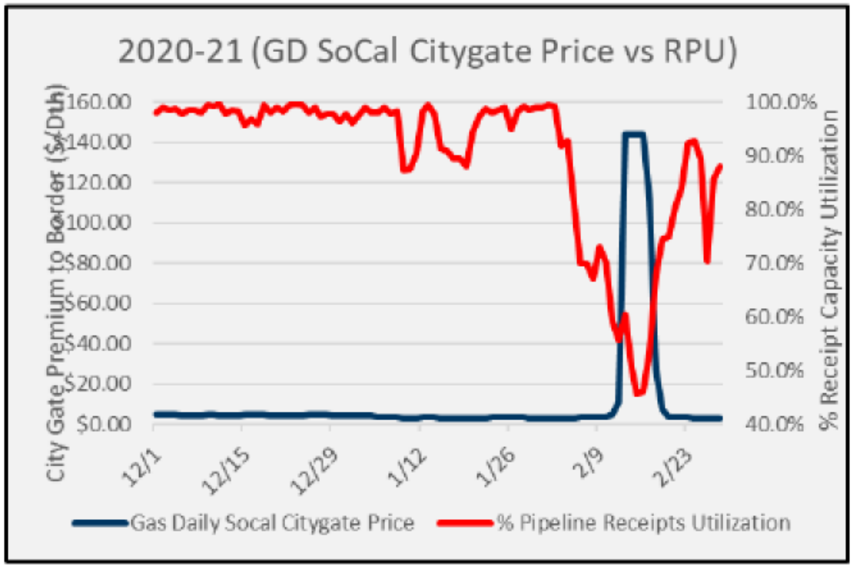
2/ *Data for 2020-21 through Feb 28, 2021.*

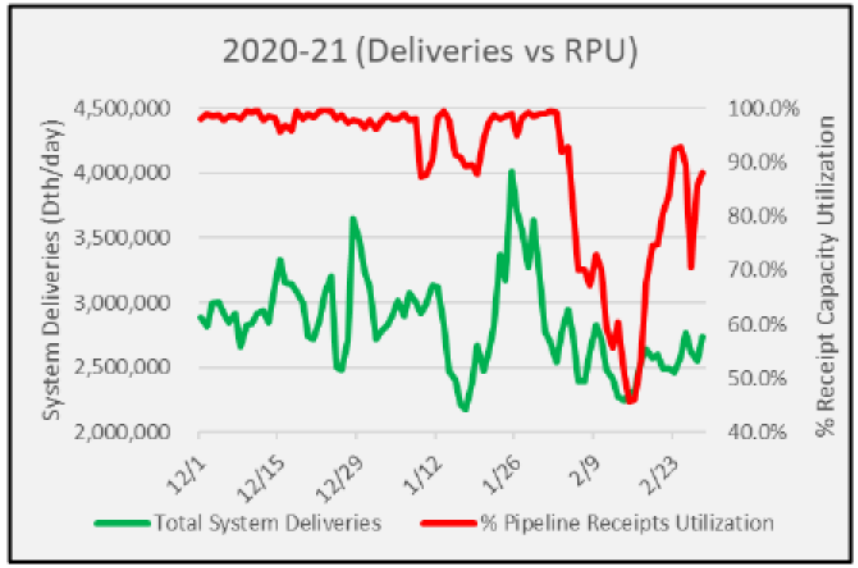
Daily Receipt Point Utilization Statistics (Dec-Feb)

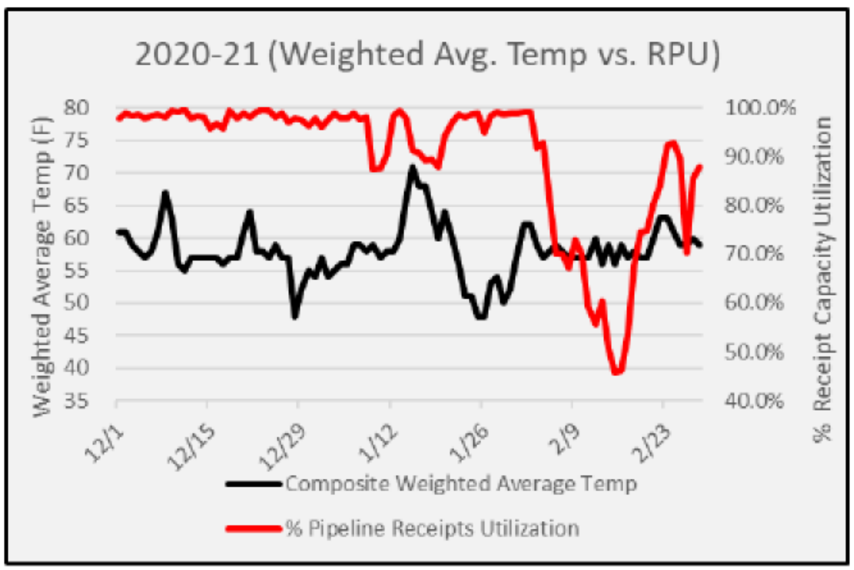
Year	Average	Max
2020-21	90.0%	99.7%
2019-20	97.2%	99.9%
2018-19	93.9%	98.8%
2017-18	85.6%	94.6%

Data reflects average total scheduled pipeline receipts as a percentage of the total available receipt capacity for the total of the Northern, Southern and Wheeler Ridge Zones

Analysis of February 2021 events







Conclusions

- Downward spike in winter RPU did not occur during low temperature / high demand period in California
- Downward spike in RPU is a direct response to high gas prices at the SoCal Border.
- Downward spike in RPU is not related to availability of takeaway capacity into the SoCal Gas system.

High sendout days analysis

Rank	Date	UF	Sendout (Dth/d)
1	02/06/2019	91.88%	4,097,000
2	12/18/2019	98.39%	4,055,000
3	02/05/2019	96.72%	4,044,000
4	01/25/2021	98.90%	4,012,000
5	02/04/2020	94.30%	4,011,000
6	02/21/2019	93.92%	3,953,000
Average		95.69%	4,032,000

On the coldest (highest sendout) days of the year from the last three winter seasons, Utilization Factor ("UF") has exceeded 95%.

Workstream 2 RPU Recommendations

Project Team RPU recommendations:

For analysis of the Gas Transmission Portfolio – **Recommend 95% RPU**

- *95% RPU consistent with recent high demand day experience*
- *95% assumes pipeline system restoration projects completed*
- *Lower RPU leads to skewed results with Gas Transmission Expansions*
- *Consider reserve capacity to protect against facility outage (seek stakeholder input)*

For analysis of all other portfolios – **Recommend Retention of 85% RPU**

- *Phase 2 Collaborative stakeholder input / CPUC analysis led to 85% RPU*
- *Pipeline system capacities consistent with Phase 2 study – no changes*

Proposed peak day receipt assumptions

Recommendations for Winter 2027 and Winter 2035:

Zone	Phase 2 RPU Assumption[1/] *(MDth/d)*	Current Available *(MDth/d)*	Nominal Capacity *(MDth/d)*	Proposed RPU *(%)*	Proposed RPU[2/,3/] *(MDth/d)*
Wheeler Ridge	765	833	765	100%	765
Southern	1,030	1,030	1,210	95%	1,150
Northern	1,250	1,031	1,590	95%	1,510
Total	**3,045**	**2,894**	**3,565**		**3,425**

[1/] Phase 2 RPU set as 85% at Southern and Northern Zones and 100% at Wheeler Ridge. FTI/GSC would continue to utilize this Winter RPU capacity in portfolio analyses that do not include incremental Gas Transmission Investments.

[2/] Proposed Phase 3 Winter RPU (applicable to Gas Transmission Investment Portfolio) based upon assumption that SoCalGas completes projects to restore system capacities to Nominal Capacity levels with RPU of 95% applied to Northern and Southern Zones. Capacities in table represent baseline that would be further expanded to meet demand requirements.

[3/] Proposed Phase 3 Winter RPU in table includes no "outage" reserve capacity.

Alternative: “N *minus* 1” reserve to offset a single “outage”

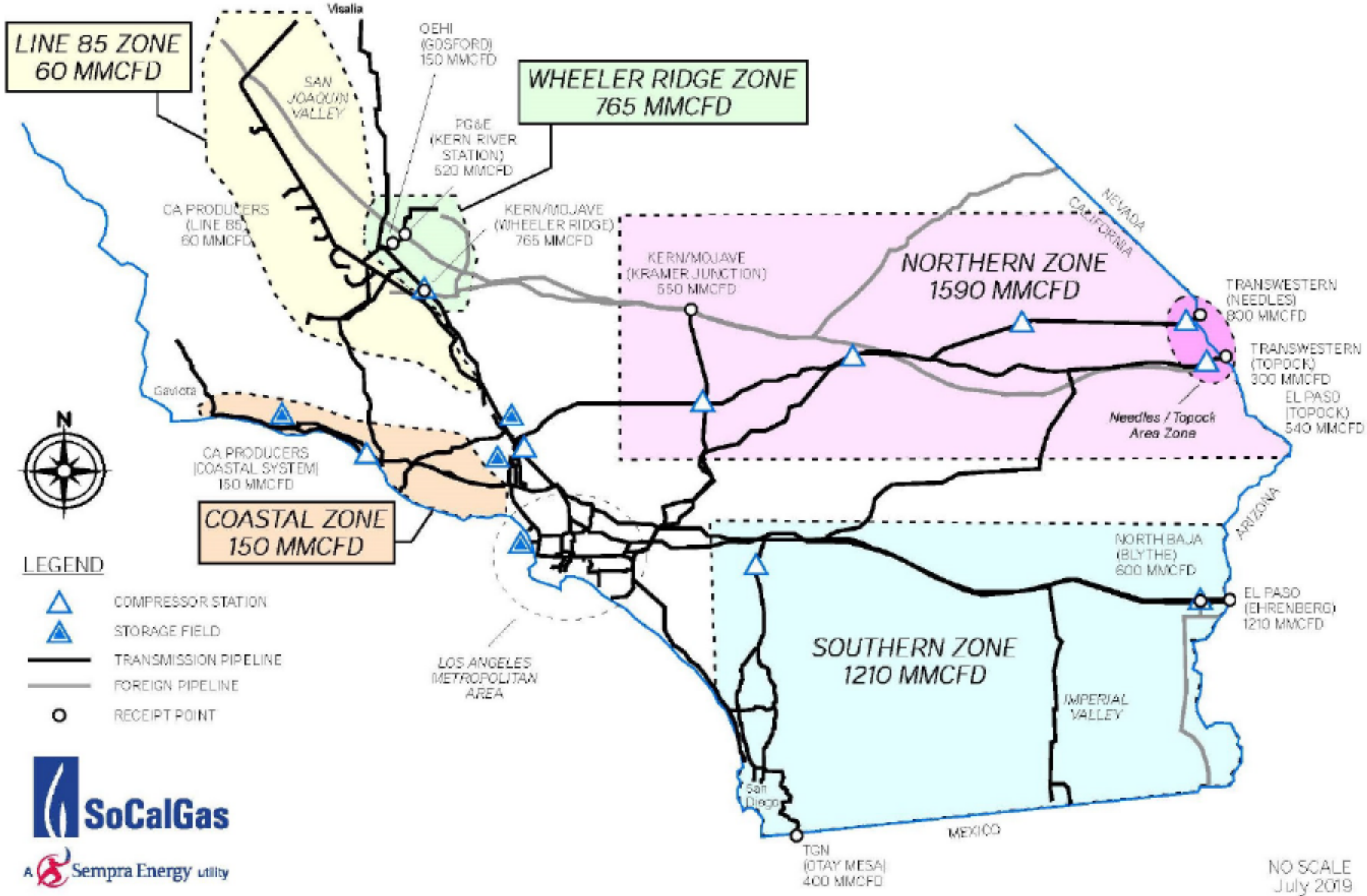
- Withdrawal capacity at Aliso Canyon coupled with non-Aliso storage and pipeline receipts currently provide reserve capacity that can be used to offset system outages on the SoCal Gas system
- Retirement of Aliso Canyon eliminates current excess reserve capacity
- FTI/GSC requests input on whether to include reserve capacity, and if so the quantity of reserve capacity, to support one “outage” event on the SoCal Gas System within Phase 3 – Workstream 2 for the Gas Transmission Investment Portfolio (85% RPU covers issue in remaining portfolios)

Recent Examples of SoCal Gas System Outages from Maintenance Report:

Event ID	SoCal Gas Envoy Event ID	Capacity Reduction
Voluntary Decrease of maximum operating pressure on L2000	2170	202 MMcfd
L4000 and L235 Operational Restrictions	4581	900 MMcfd
L3000 Operational Restrictions	4582	190 MMcfd
L85 Pipeline Maintenance – Compliance	4849	20 MMcfd
L2001 Pipeline Relocation - Reliability	4856	150 MMcfd
Compressor Station Maintenance – Compliance (Ehrenburg/Blythe)	4878	395 MMcfd
Compressor Station Maintenance – Compliance (Wheeler Ridge Zone)	4870	115 MMcfd

Note: Within PGE’s 2019 Gas Transmission and Storage Rate Case, in addition to a 95% RPU Assumption, PGE included Reserve Capacity of 250 MMcfd to support one facility outage event on the Gas Transmission System

SoCal Gas nominal capacity



Source: SoCal Gas

Balancing analysis

Objectives for seasonal storage review:

1. *Are Non-Aliso Storage assets sufficient for seasonal balancing requirements?*
2. *Is 90% storage inventory assumption reasonable to support winter peak day?*

Annual mass balance analysis in 2027/28 or 2035/36

Assumptions:

- Aliso Canyon retired / All non-Aliso storage in service
- Reserve injection quantity of 345 MMcfd for balancing (historic injection capacity allocated to the balancing function)
- Projected 2027 & 2035 monthly demand sourced from California Gas Report
  - Demand for average temperature year
  - Demand for cold temperature (1 in 35 Cold Year) & Dry Hydro year
- Non-Aliso Canyon storage winter season inventory starting balance: 48 Bcf
- Pipeline capacity of 3,055 MMcfd[1/] and 90% utilization
- Injection / withdrawal capacity based on 2019 SoCal Gas DR response storage curves [2/]

[1/] *3,055 MMcfd breakdown illustrated on next slide.*

[2/] *(SoCal Gas Response Dated July 23, 2019 to CPUC-Energy Division Data Request Dated July 22, 2019 pursuant to PUC Section 583, GO 66-D and D.17-09-023)*

Seasonal assumptions for balancing analysis

SCG Pipeline Capacity	
California Production	60
Wheeler Ridge	765
North Needles	400
Topock	300
Kramer Junction	550
Northern Zone	1,250
Blythe/Ehrenberg	980
Otay Mesa	0
Southern Zone	980
Total	**3,055**
Load Factor	
California Production	100%
Wheeler Ridge Zone (KR, MP, PG&E, OEHI)	90%
Northern Zone (TW,EPN,QST, KR)	90%
Southern Zone (EPN,TGN,NBP)	90%
Total	**90%**
SCG Pipeline Capacity Utilized	
California Production	60
Wheeler Ridge Zone (KR, MP, PG&E, OEHI)	689
Southern Zone (EPN,TGN,NBP)	1,125
Northern Zone (TW,EPN,QST, KR)	882
Total	**2,756**

California Production: Recent historical production

Northern Zone: North Needles & Topock capacity reductions (Line 3000 temporary pressure reduction and operating pressures of Line 235-2 and Line 4000)

Southern Zone: Zone capacity of 1,210 MMcfd

- Blythe/Ehrenberg: SCG capacity 980 MMcfd PSEP; loss Line 2000 right-of-way
- Otay Mesa: Capacity 400 MMcfd. Assume 0 MMcfd supply seasonally

Balancing analysis results: Apr 27-March 28

SCG: Seasonal Balancing & Storage Evaluation / Apr27-Mar28												
	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28
Monthly Storage Injection Assessment (CGR Average Temperature with Base Hydro Year) (MMcf)												
FOM Inventory	44,600	45,200	45,820	46,420	47,009	47,412	47,712	47,960	47,960	42,923	42,923	42,923
FOM WD Capacity (MMcfd)	1,210	1,220	1,230	1,240	1,249	1,256	1,261	1,375	1,375	1,294	1,294	1,294
CGR Demand	62,340	55,645	52,110	62,496	70,773	66,450	63,705	71,340	90,458	83,235	76,579	69,264
Pipeline Supply	82,665	85,421	82,665	85,421	85,421	82,665	85,421	82,665	85,421	85,421	79,910	85,421
Storage Inj (+) / WD (-)	600	620	600	589	403	300	248	0	(5,038)	0	0	1,736
Excess (+) / Short (-)	19,725	29,156	29,955	22,336	14,245	15,915	21,468	11,325	0	2,186	3,330	14,420
Month End Inventory	45,200	45,820	46,420	47,009	47,412	47,712	47,960	47,960	42,923	42,923	42,923	44,659
Monthly Storage Injection Assessment (CGR Cold Temperature with Dry Hydro Year) (MMcf)												
FOM Inventory	30,800	34,250	37,474	40,294	42,650	44,448	45,798	46,945	47,995	34,898	29,540	26,772
FOM WD Capacity (MMcfd)	987	1,043	1,095	1,141	1,179	1,208	1,230	1,359	1,376	1,164	1,077	1,033
CGR Demand	65,820	57,784	53,880	64,976	74,152	69,150	66,309	76,020	98,518	90,778	82,776	73,894
Pipeline Supply	82,665	85,421	82,665	85,421	85,421	82,665	85,421	82,665	85,421	85,421	79,910	85,421
Storage Inj (+) / WD (-)	3,450	3,224	2,820	2,356	1,798	1,350	1,147	1,050	(13,098)	(5,358)	(2,866)	4,030
Excess (+) / Short (-)	13,395	24,413	25,965	18,089	9,471	12,165	17,965	5,595	0	0	0	7,497
Month End Inventory	34,250	37,474	40,294	42,650	44,448	45,798	46,945	47,995	34,898	29,540	26,772	30,802

Balancing analysis results: Apr 35-March 36

SCG: Seasonal Balancing & Storage Evaluation / Apr35-Mar36												
	Apr-35	May-35	Jun-35	Jul-35	Aug-35	Sep-35	Oct-35	Nov-35	Dec-35	Jan-36	Feb-36	Mar-36
Monthly Storage Injection Assessment (CGR Average Temperature with Base Hydro Year) (MMcf)												
FOM Inventory	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000
FOM WD Capacity (MMcfd)	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,376	1,376	1,376	1,376	1,376
CGR Demand	59,070	53,413	48,960	57,598	64,418	59,460	57,381	65,580	84,382	79,047	73,442	66,436
Pipeline Supply	82,665	85,421	82,665	85,421	85,421	82,665	85,421	82,665	85,421	85,421	79,910	85,421
Storage Inj (+) / WD (-)	0	0	0	0	0	0	0	0	0	0	0	0
Excess (+) / Short (-)	23,595	32,008	33,705	27,823	21,003	23,205	28,040	17,085	1,039	6,374	6,467	18,985
Month End Inventory	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000
Monthly Storage Injection Assessment (CGR Cold Temperature with Dry Hydro Year) (MMcf)												
FOM Inventory	43,000	44,200	45,316	46,096	46,716	47,181	47,631	47,910	47,910	41,633	40,863	40,863
FOM Capacity (MMcfd)	1,184	1,204	1,222	1,234	1,244	1,252	1,259	1,374	1,374	1,273	1,260	1,260
CGR Demand	61,980	54,839	49,800	59,644	66,278	62,310	59,458	69,510	91,698	86,190	79,040	70,825
Pipeline Supply	82,665	85,421	82,665	85,421	85,421	82,665	85,421	82,665	85,421	85,421	79,910	85,421
Storage Inj (+) / WD (-)	1,200	1,116	780	620	465	450	279	0	(6,278)	(769)	0	2,170
Excess (+) / Short (-)	19,485	29,466	32,085	25,157	18,678	19,905	25,684	13,155	0	(0)	870	12,425
Month End Inventory	44,200	45,316	46,096	46,716	47,181	47,631	47,910	47,910	41,633	40,863	40,863	43,033

Annual mass balancing results

Non-Aliso Storage meets system requirements with one (minor) exception

- Apr27-Mar28: Storage injection capacity dedicated to balancing in cold year event reduced to 335 MMcf/d (from target 345 MMcf/d) during October and November

Non-Aliso Fields Support Seasonal Demand in 2027-28 and Beyond

- Declining demand post 2027-28 results in lower seasonal storage requirements

These results indicate that system requirements can be met without Aliso Canyon during the entirety of the study period.

Balancing analysis results are not aligned with Phase 2 inputs

The Phase 2 analysis included an assumption for 90% storage inventory, resulting in 1,329 MMcf/d in withdrawal capacity at the non-Aliso storage facilities. The balancing analysis indicates that winter storage inventories will fall below this level in each of Winter 2027/28 and Winter 2035/36.

Non-Aliso Storage Withdrawal Capability *(MMcf/d)*

		2027/28		2035/36	
	Phase 2 Assumption	Normal Weather	Cold Temp/ Dry Hydro	Normal Weather	Cold Temp/ Dry Hydro
Nov	1,329	1,375	1,359	1,376	1,374
Dec	1,329	1,375	1,376	1,376	1,374
Jan	1,329	1,294	1,164	1,376	1,273
Feb	1,329	1,294	1,077	1,376	1,260
Mar	1,329	1,294	1,033	1,376	1,260

Resolution of the storage inventory assumption is on the critical path for Workstream 2. At lower inventory levels, the amount of new infrastructure needed to facilitate Aliso's retirement increases. Within the range of possible adjustments, impacts to final findings could be large.

Requests for input

In addition to other input that participants would like to provide, the Project Team specifically requests comments on the following topics:

1. Should the 85% RPU assumption be retained for the portfolios other than gas transmission for consistency with Phase 2 analyses?
   - If not, what assumption should be made instead? Please provide a basis for recommended alternatives.

2. Is the 95% RPU assumption for the gas transmission analysis reasonable?
   - If not, what assumption should be made instead? Please provide a basis for recommended alternatives.
   - Is it reasonable to have an RPU assumption for this portfolio that is different from the one used to analyze other portfolios? Why or why not?

3. Should the 90% storage inventory assumption be retained for consistency with Phase 2 analyses?
   - If not, what assumption should be made instead? Please provide a basis for recommended alternatives.
   - Does the balancing analysis provide a basis to adjust the inventory assumption? In other words, should the 2027/28 and 2035/36 assumptions be set based on the balancing analysis?

Questions

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Electric transmission portfolio

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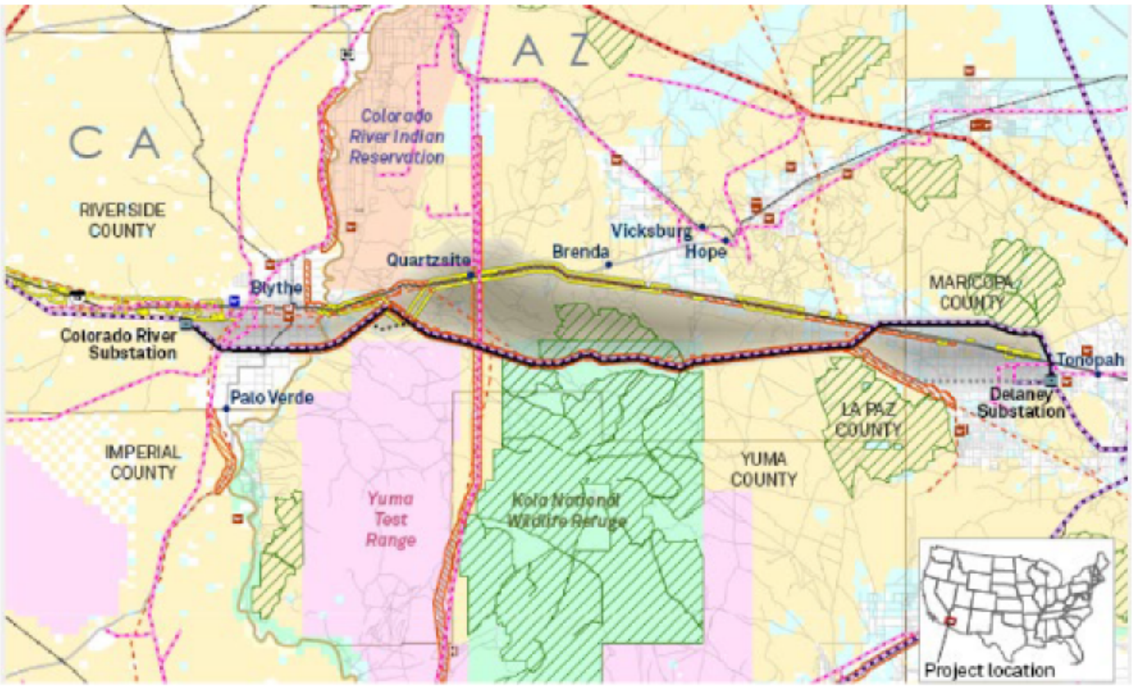
Electric transmission portfolio



Close the MW gap by adding new transmission into California from surrounding markets. Project specifications will be based on actual projects currently in development including the **10 West Link**, **Silverado Renewables Connection**, or other projects.

Project costs will be estimated based on filings made by project developers, including permitting applications in CA and AZ, FERC filings, and, potentially, other sources.

All projects assume 2035 ISD.

The Project Team is currently considering which projects to model, how to scale them, and how to analyze their impacts on California's import capability. Input and feedback on these two topics would be particularly beneficial.

Source: S&P Global

SoCal transmission links

Lugo could serve as substation potentially to connect resources from Southern Nevada to Southern California

Current 500 kV line from Palo Verde and the planned 500 kV Ten West line connect to Devers

Goal

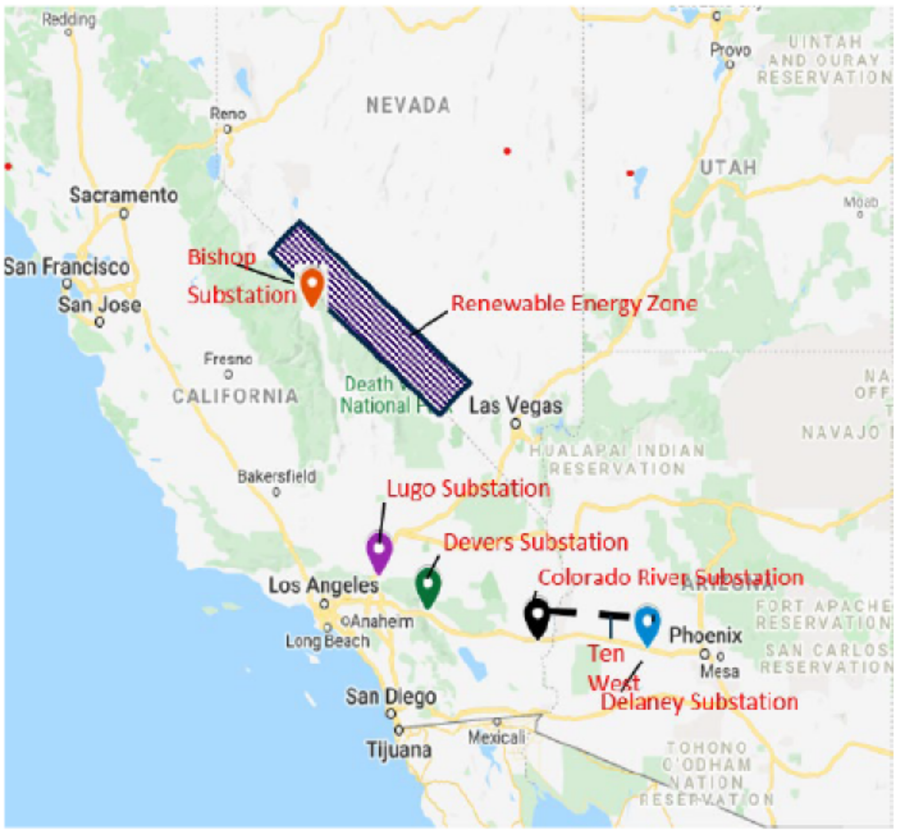
- Solve the Electric Generation Shortfall of 2,866 MW in 2035 by increasing electric transmission into Southern California from other states with abundant renewable resources

Portfolio Design Considerations

- Use real-world proposals/projects to define project
- Specify rating of new line in MW (~ 3,000 MW to cover 2035 shortfall)
- Adjust transmission flow limits on relevant lines in FTI's PLEXOS model
- Modify maximum import limit into CAISO to reflect addition of the project

Source: CAISO

Transmission project concepts



Concept	Discussion
Project Concept 1: New capacity from Arizona to Southern California	• Information from **the Ten West 500kV from Delaney** (in Arizona) to the Colorado River substation (~120 miles). with approval expected in 2021 can provide a basis to design Transmission portfolio. [Colorado River Station~ 100 miles from Devers) • CAISO testimony in Ten West certificate proceeding showed net positive economic benefits of line based largely on the access it provides to large queue of Arizona solar projects with a lower cost structure than similar California resources • Ten West has nominal rating of 3,200 MW; CAISO's power flow modeling allowed for a deliverable capacity for RA purposes of ~30% of nominal rating (i.e., 969 MW) due to other transmission limiting conditions
Project Concept 2: New capacity from Southern Nevada to Southern California	• **Silverado Renewables Connection** currently being studied (no specific availability date) can provide a basis to design the Transmission portfolio • Silverado contemplates three phases: – Phase One: Upgrade existing 230-kV infrastructure in Nevada renewable energy zones to expand access to ~ 2,600 MW of renewables that potentially could be developed – Phase Two: Additional 1,250 MW of capacity into California by connecting current transmission system in Nevada to Bishop, Calif. – Phase Three: Further build-out to increase transmission capacity into California – and specifically Southern California (Bishop, CA to Lugo, CA ~ 240 miles)

Source: Google

Transmission line impacts

For the Transmission Portfolio, we propose to assume that the winter capability increase will be equal to the nominal capacity of the new infrastructure This means that we will increase the transmission flow limits between the origin and destination BAs by the nominal line capability. We also intend to increase the maximum import capability into CAISO from outside by the same nominal capacity. We do not intend to adjust capability based on the (summer) deliverability of the line, as is typical when calculating Resource Adequacy ("RA") contract contributions. The Project Team would like to hear input on the perceived reasonableness of these assumptions

Calculations of how much a transmission line can deliver towards RA depends on other limiting conditions on the transmission system. A separate adjustment may be required for resource availability or variability (for renewables)

Nominal line capacity	1,000 MW
Adjustment for system limiting conditions	-400 MW
Deliverable capacity after adjustments due to system limits (summer conditions)	600 MW
RA Capacity (adjusted for resource variability)	0.15*600 = 90 MW

Nominal Line capacity	1,000 MW
Deliverable capacity (winter)	1,000 MW
Resources dispatched to meet Southern California shortfall	Depends on resource production profile, which varies by hour for renewables

Adjustments are less relevant to winter conditions, during which significant amounts of generation are available because electric demand is lower and transmission paths are less constrained. It is therefore likely that new transmission infrastructure can import at close to nominal capacity, even if its RA contribution is lower.

Requests for input

In addition to other input that participants would like to provide, the Project Team specifically requests comments on the following topics:

1. Is there a preference between Concept 1 (Ten West) and Concept 2 (Silverado)? Please explain rationale.

2. How can the project team develop a reasonable estimate of how the addition of lines, whose notional capacity is known, will affect the following:
   - Transmission flow limits between the regional balancing authorities
   - The maximum import capacity into CAISO from the rest of WECC

3. Are there better approaches to developing the Transmission portfolio ones we have presented today? Please recommend specific alternatives.

Questions

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Comments and discussion

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Thank you.

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